PROPOSED

PERMIT APPLICATION REVIEW
COVERED SOURCE PERMIT (CSP) NO. 0238-01-C
Permit Renewal Application No. 0238-03

Applicant: Hawaiian Electric Company, Inc. (HECO)
Facility: Honolulu Generating Station
Location: 170 Ala Moana Boulevard, Oahu
Address: Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawaii 96840-0001

Responsible Official: Lawrence G. Ornellas
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Equipment:

Unit	Description
8	56 MW, 589 MMBtu/hr Babcock and Wilcox boiler, contract no. RB-210, national board no. 18298, with six (6) oil fired burners and propane fired igniter servicing each burner.
9	57 MW (nominal), 631.5 MMBtu/hr Babcock and Wilcox boiler, contract no. RB-259, national board no. 19200, with six (6) oil fired burners and propane fired igniter servicing each burner.

1. Background

1.1 HECO has applied for a permit renewal with modifications/revisions for operating Boilers 8 and 9 at Honolulu Generating Station. Boiler 8 has a capacity of 56 MW and the capacity of Boiler 9 is 57 MW. The boilers are fired on either fuel oil No. 6 or fuel oil No. 2 with as much as 0.5% sulfur content. The boilers are also allowed to burn specification used oil not to exceed the limits in Paragraph 2.14 of this review. Igniters for the boiler burners are fired on propane. Also, the total specification used oil consumption for the boilers is limited to 5,000 gallons per year. This facility is a major source for new source review (NSR) pollutants. The facility is not a major source for hazardous air pollutants (HAPs). The Standard Industrial Classification Code for this facility is 4911 (Electrical Power Generation Through Combustion of Fossil Fuels).

1.2 The following modifications/revisions were proposed for the permit renewal:

Modification/Revision	Status
Increase the 5,000 gallon per year total combined specification used oil fuel limit for Boilers 8 and 9 to a 15,000 gallon per year total combined specification used oil fuel limit.	Made change as applicable
Revise the specification used oil testing frequency and semi-annual reporting to match HECO's Waiau CSP permit	Updated specification used oil testing to that specified for Kahe Generating Station
Proposed alternate operating scenario to replace each boiler with a temporary replacement unit.	Not considered an alternate operating scenario

2. Applicable Requirements

2.1 Hawaii Administrative Rules (HAR)
Title 11 Chapter 59, Ambient Air Quality Standards
Title 11 Chapter 60.1, Air Pollution Control
Subchapter 1 - General Requirements
Subchapter 2 - General Prohibitions
11-60.1.31 Applicability
11-60.1-32 Visible Emissions
11-60.1-38 Sulfur Oxides from Fuel Combustion
11,60.1-39 Storage of Volatile Organic Compounds
Subchapter 5 - Covered Sources
Subchapter 6 - Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
11-60.1-111 Definitions
11-60.1-112 General Fee Provisions for Covered Sources
11-60.1-113 Application Fees for Covered Sources
11-60.1-114 Annual Fees for Covered Sources

2.2 40 Code of Federal Regulations (CFR) Part 52, §52.21, PSD of Air Quality is not applicable to Boilers 8 and 9 (built in 1954 and 1957, respectively) because the units are grandfathered from PSD and no changes have been proposed for the units that trigger PSD review. The proposal to increase the specification used oil consumption from 5,000 gallons per year to 15,000 gallons per year does not trigger PSD review because potential pollutant emissions for the change are below significant emission thresholds (see table below).

Regulated NSR Pollutant	Maximum Potential Emissions (TPY)	Significant Emissions Threshold (TPY)
PM	1.3	25
PM_{10}	1.0	15
$PM_{2.5}$	1.0	10
SO_2	1.6	40
H_2SO_4	0.2	7
NO_2	0.1	40
CO	0.02	100
VOC	0.01	40
Pb	0.005	0.6

2.3 40 CFR Part 60, NSPS, Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators is not applicable to Boilers 8 and 9 because the units were constructed prior to August 17, 1971 and there are no changes proposed that would trigger Subpart D requirements. Pursuant to 40 CFR §60.14, a modification is any physical change to an existing facility which results in a kg/hr increase in the emission rate. The proposal to increase the specification used oil limit from 5,000 gallons per year to 15,000 gallons per year does not increase the kg/hr emission rate. The boilers have already been permitted to burn up to 5,000 gallons per year of specification used oil and changes in the yearly consumption of this fuel do not change short term emission rates. See Paragraph 2.11 of this review.

2.6 40 CFR Part 60, NSPS, Subpart Da, Standards of Performance for Fossil-Fuel-Fired Steam Generating Units for Which Construction is Commenced After September 18, 1978 is not applicable to Boilers 8 and 9 because the units were constructed prior to September 18, 1978. Also, there are no changes proposed that would require compliance with NSPS requirements. See Paragraph 2.3 of this review.

2.7 40 CFR Part 60, NSPS, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units is not applicable to Boilers 8 and 9 because the units were constructed prior to June 19, 1984. Also, there are no changes proposed that would require compliance with NSPS requirements. See Paragraph 2.3 of this review.

2.8 40 CFR Part 60, NSPS, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units does not apply to Boilers 8 and 9 because the units were constructed prior to 1989 and are above 100 MMBtu/hr in capacity.

2.9 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart DDDDD for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters is not applicable to Boilers 8 and 9 because Honolulu Generating Station is not a major source for hazardous air pollutants (HAPs).

2.10 40 CFR Part 63, Subpart JJJJJJ, NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources is not applicable to Boilers 8 and 9 because the units are electric utility steam generating units (EGUs) covered by Subpart UUUUU.

2.11 40 CFR Part 63, Subpart UUUUU, NESHAPs: Coal- and Oil-Fired Electric Utility Steam Generating Units is applicable to Boilers 8 and 9 because the units meet the definition of an electric utility steam generating unit (EGU). An EGU means any fossil fuel-fired combustion unit of more than 25 megawatts electric (MW_e) that serves a generator that produces electricity for sale. Electricity generated from steam supplied by the boilers is used for sale and each boiler's capacity is greater than 25 MW. Honolulu Generating Station must comply with 40 CFR Part 63, Subpart UUUUU no later than April 16, 2015.

2.12 The following table summarizes HAR opacity limits, and explanations for selecting permit opacity limits for Boilers 8 and 9:

Boiler	Subpart D Opacity Limit	HAR Opacity Limit[2]	Permit Opacity Limit	Reason for Permit Limit
Units 8 and 9 Other than startup, shutdown, and malfunction	------------	40%	40%	HAR §11-60.1-32(a) for sources operating before March 21, 1972
Units 8 and 9 Startup, shutdown, and malfunction	------------	not more than 60% for more than six minutes in any sixty minute period	not more than 60% for more than six minutes in any sixty minute period	HAR §11-60.1-32(a)

2.13 The purpose of Compliance Assurance Monitoring (CAM) is to provide reasonable assurance that compliance is being achieved with large emission units that rely on air pollution control device equipment to meet an emissions limit or standard. Pursuant to 40 CFR Part 64, for CAM to be applicable, the emissions unit must: (1) be located at a major source; (2) be subject to an emissions limit or standard; (3) use a control device to achieve compliance; (4) have potential pre-control emissions that are greater than the major source level; and (5) not otherwise be exempt from CAM. There are no emission limits from standards prior to November 15, 1990. Therefore, CAM is not applicable.

2.14 Specification used oil requirements for Boilers 8 and 9 are listed as follows:

Constituent/Property	Allowable Limit
Sulfur	≤ 2 % by weight
Arsenic	≤ 5 ppm
Cadmium	≤ 2 ppm
Chromium	≤ 10 ppm
Lead	≤ 100 ppm
Total Halogens	≤ 1,000 ppm
Flash Point	≥ 100 ^{O}F
PCBs	< 2 ppm

2.15 Annual emissions reporting is required because this facility is a covered source.

2.16 The consolidated emissions reporting rule (CERR) applies. The PM_{10}, NO_X, and SO_2 emissions from the facility exceed the following reporting levels in 40 CFR §51, Subpart A for type A sources:

CERR APPLICABILITY			
Pollutant	Facility Emissions	CERR Triggering Levels (TPY)	
		1 year cycle (type A sources)	3 year cycle (type B sources)
PM_{10}	604.4	≥ 250	≥ 100
SO_2	2,833.7	≥ 2,500	≥ 100
NO_X	3,597.7	≥ 2,500	≥ 100
VOC	54.5	≥ 250	≥ 100
CO	172.8	≥ 2,500	≥ 1,000

2.17 A best available control technology (BACT) analysis is not required because there are no modifications proposed for the facility that increase emissions above significant level. See Paragraph 2.2 of this review.

2.18 The facility is not a synthetic minor source because it is already a major source.

2.19 The facility is subject to the greenhouse gas (GHG) reporting requirements specified in 40 CFR Part 98 because the total greenhouse gas emissions on a CO_2 equivalent (CO_2e) basis are greater than 25,000 metric tons per year. The GHG emissions for permitted equipment are shown in Paragraph 6.4. The CO_2e emissions determined in metric tons from the global warming potential (GWP) of each GHG are shown in the table below.

Biogenic Non-Biogenic GHG Emissions			
GHG	GWP	GHG Mass-Based Emissions (metric tons/yr)	CO_2e Based Emissions (metric tons/yr)
carbon dioxide (CO_2)	1	801,480.5	801,480.5
Methane (CH_4)	21	32.0	672.0
Nitrous Oxide (N_2O)	310	6.4	1,984
		Total→	804,136.5

3. Insignificant Activities

3.1 Insignificant activities identified by the applicant that meet the exemption criteria specified in HAR§11-60.1-82(f) and (g) are listed as follows:

a. Storage tanks less than 40,000 gallons storing volatile organic compounds are exempt in accordance with HAR, §11-60.1-82(f)(1);
b. Fuel burning equipment with a heat input less than one (1) MMBtu/hr are exempt in accordance with HAR, §11-60.1-82(f)(2) ;
c. A 200 kW emergency diesel engine generator is exempt pursuant to HAR, §11-60.1-82(f)(5);
d. Paint spray booths are exempt in accordance with HAR, §11-60.1-82(f)(6);
e. Welding booths are exempt in accordance with HAR, §11-60.1-82(g)(7); and
f. Fugitive leaks from valves, flanges, pump seals, and VOC water separators are considered exempt in accordance with HAR, §11-60.1-82(f)(7).

4. Alternate Operating Scenario

4.1 Upon receiving written approval from the Department of Health, the permittee may fire Boilers 8 and 9 on an alternate fuel (e.g., but not limited to biofuel) if the boilers were capable of accommodation the fuel and burning the fuel does not cause a modification as defined in any applicable federal or state regulation (e.g., PSD, NSPS, NESHAP, and HAR).

5. Air Pollution Control

5.1 There are no air pollution controls for the boilers.

6. Project Emissions

6.1 Emissions were estimated for burning 10,000 additional gallons per year of specification used oil and compared to those for burning either fuel oil No. 2 or 6. Emissions for firing fuel oil No. 2 or 6 were based on emission factors from the applicant. Emissions for firing specification used oil were based on emission factors from AP-42, Section 1.11, Waste Oil Combustion. Emission increases from combusting 15,000 gallons per year of either fuel oil No. 2 or No. 6 are compared to those for firing 15,000 gallons per year of specification used oil are summarized in the table below. Emissions are estimated in Enclosure (1).

Emissions for Firing Fuel Oil Compared to Those for firing Spec Used Oil			
Pollutant	15,000 gal/yr F.O. # 2 or F.O. #6 (TPY)	15,000 gal/yr Specification Used Oil (TPY)	Emissions Increase (TPY)
PM	0.16	1.3	1.14
PM_{10}	0.13	1.0	0.87
$PM_{2.5}$	0.07	1.0	0.87
SO_2	0.60	1.6	1.00
H_2SO_4	0.08	0.2	0.12
NO_2	0.35	0.1	-0.25
CO	0.08	0.02	-0.06
VOC	0.01	0.01	0
Lead	5.94E-06	4.95E-03	4.94E-06

6.2 Boiler emissions of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds VOCs, particulate matter (PM), particulate matter less than ten (10) microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and hazardous air pollutants (HAPs) were evaluated. The NO_X, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ emissions were based on AP-42 emissions factors from Section 1.3 (5/10), Fuel Oil Combustion. A heating value of 150,000 Btu/gal was assumed for fuel oil No. 6 to convert emission factors from lb/1,000 gal to lb/MMBtu. Emission estimates were based on emission factors or firing fuel oil No. 6 as worst-case scenario. The boilers are also permitted to burn fuel oil No. 2. A mass balance calculation was used to determine SO_2 emissions based on the maximum allowable fuel sulfur content of 0.5% by weight for fuel oil No. 6, a fuel oil No. 6 heating value 18,847 Btu/lb, and each boiler's maximum heat rate input. The AP-42 emission factors used to estimate emissions from the boilers were increased by a factor of safety. The H_2SO_4 emission rate was based on information from source testing that indicated H_2SO_4 emissions are proportional to 13.12% of the SO_2 emission rate. It was assumed that 45% of the total particulate was $PM_{2.5}$ and 79% of the total particulate was PM_{10} based on AP-42, Appendix B.2, Table B.2-2 (Page B.2-12) for boilers firing a mixture of fuel including petroleum. The HAP emissions were based on AP-42 emission factors from either 1994 Waiau 7 test data or the EPRI PISCES Air Toxic Data Base. Emissions are estimated in Enclosures (2) and (3) and summarized in the tables below.

56 MW (589 MMBtu/hr) Boiler 8 Emissions			
Pollutant	Boiler Emissions		Boiler Emissions (TPY)
	lb/hr	g/s	8,760 hr/yr operation
SO_2	312.224	39.422	1,367.5
H_2SO_4	40.964	5.172	179.4
NO_X	396.397	50.050	1,736.2
CO	39.463	4.983	172.8
VOC	-------	--------	26.3
PM	64.709	8.181	283.8
PM_{10}	51.184	6.463	224.2
$PM_{2.5}$	29.156	3.681	127.7
HAPs	-------	-------	3.6
Beryllium	-------	-------	0.003
Cadmium	-------	-------	0.006
Chromium	-------	-------	0.001
Lead	-------	-------	0.014
Manganese	-------	-------	0.057
Mercury	-------	-------	0.013
Nickel	-------	-------	3.4

57 MW (631.5 MMBtu/hr) Boiler 9 Emissions			
Pollutant	Boiler Emissions		Boiler Emissions (TPY)
	lb/hr	g/s	8,760 hr/yr operation
SO_2	334.753	42.267	1,466.2
H_2SO_4	43.920	5.545	192.4
NO_X	425.000	53.662	1,861.5
CO	42.311	5.342	185.3
VOC	-------	--------	28.2
PM	109.881	13.874	481.3
PM_{10}	86.806	10.960	380.2
$PM_{2.5}$	49.446	6.243	13.7
HAPs	-------	-------	3.8
Beryllium	-------	-------	0.003
Cadmium	-------	-------	0.006
Chromium	-------	-------	0.001
Lead	-------	-------	0.015
Manganese	-------	-------	0.061
Mercury	-------	-------	0.014
Nickel	-------	-------	3.6

6.3 Total yearly emissions from operating the boilers are listed below as follows:

TOTAL EMISSIONS	
Pollutant	Potential Emissions (TPY)
	Boilers 8 and 9
SO_2	2,833.7
H_2SO_4	371.8
NO_X	3,597.7
CO	172.8
VOC	54.5
PM	765.1
PM_{10}	604.4
$PM_{2.5}$	507.9
HAPs	7.4
Berylium	0.006
Cadmium	0.012
Chromium	0.002
Lead	0.028
Manganese	0.118
Mercury	0.027
Nickel	7.0

6.4 Total GHG emissions from Boilers 8 and 9 were determined with emission factors from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. The GHG emissions were determined in Enclosure (4) and summarized in the table below.

TWO BOILERS			
	Emissions (short tons) TPY[a]		
	Carbon Dioxide (CO_2)	Methane (CH_4)	Nitrous Oxide (N_2O)
Boiler 8 Emissions (short tons)	426,237.9	17.0	3.4
Boiler 9 Emissions (short tons)	456,993.6	18.3	3.7
Total GHG Emissions (short tons)	883,231.5	35.3	7.1
Total GHG Emissions (metric tons)[a]	801,480.5	32.0	6.4

a: 1 metric ton = 1.102 short tons.

7. Air Quality Assessment

7.1 There are no changes proposed for the facility that increase emissions above those specified in HAR §11-60.1-82(f)(7). Therefore, an air modeling assessment was not performed.

8. Significant Permit Conditions

8.1 Except as specified in the permit for fuel fired by the igniters, Boilers 8 and 9 shall be fired only on one or a combination of the following fuels:

a. Fuel oil No. 6 with a maximum sulfur content not to exceed 0.5% by weight;
b. Fuel oil No. 2 with a maximum sulfur content not to exceed 0.5% by weight; and
c. Specification used oil meeting the requirements specified in permit that will be verified by laboratory analysis.

Reason for 8.1: These are fuels that were proposed by the applicant for operating the boilers. The fuel sulfur content limits were used in the modeling assessments that showed compliance with the ambient air quality standards for SO_2.

8.2 The total combined specification used oil fired by Boilers 8 and 9, shall not exceed 15,000 gallons in any rolling twelve-month (12-month) period.

Reason for 8.2: This limit was proposed by the applicant for firing specification used oil in Boilers 8 and 9.

8.3 Incorporate alternate operating scenario that would allow the permittee to switch fuels for Boilers 8 and 9.

Reason for 8.3: Boilers 8 and 9 were installed prior to 1975 and may burn an alternate fuel without triggering a permit modification in accordance with state and federal regulations. Pursuant to 40 CFR §52.21(b)(1)(iii), use of an alternative fuel does not cause a modification if the source was capable of accommodating the fuel before January 6, 1975. Additionally, if a boiler was in existence prior to the date of other federal regulations, such as NSPS, and was always capable burning the fuel, a modification may not be triggered. Also, Pursuant to HAR, §11-60.1-81, an increase in the emissions of any air pollutant above permitted emission limits would be a significant modification.

8.4 Specify 40 CFR Part 63, Subpart UUUUUU requirements for Boilers 8 and 9 that must be met by April 16, 2015.

Reason for 8.4: Incorporate pursuant to Paragraph 2.11 of the permit application review.

8.5 Specify opacity limits for Boilers 8 and 9.

Reason for 8.5: Incorporate pursuant to Paragraph 2.12 of the permit application review.

9. Conclusion and Recommendation:

Maximum potential emissions were based on boilers maximum capacity. Actual capacity of the units will vary depending on operating load. Visible emissions monitoring is specified for the boilers to ensure that opacity limits are met. Recommend issuance of the covered source permit subject to the significant permit conditions, thirty-day (30-day) public comment period, and forty-five-day (45-day) review by EPA.

Mike Madsen, April 24, 2013